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STAFF REPORT

SUMMER 2010 ELECTRICITY SUPPLY AND DEMAND OUTLOOK

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CALIFORNIA ENERGY COMMISSION

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ABSTRACT

The *Summer 2010 Electricity Supply and Demand Outlook* provides a summary of the California Energy Commission staff assessment of electricity system or grid capability to provide power to meet peak electricity demand within California.

Keywords: Supply and demand outlook, probability, operating reserve, loss of load, demand, forced outage, generation, net interchange, demand response, interruptible load, reserve margin

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EXECUTIVE SUMMARY

The *Summer 2010 Electricity Supply and Demand Outlook* provides a summary of the California Energy Commission staff assessment of the physical electricity system's capability to meet peak electricity demand in California from June through September 2010. This assessment includes the entire state and three smaller geographic subregions of interest: the California Independent System Operator (California ISO) Balancing Authority Area and the northern and southern subregions of the California ISO.[1]

California is expected to have more-than-adequate electricity supplies to meet peak demand this summer, even if hotter-than-average temperatures occur. Two primary factors support this assessment. First, there is an overall increase in generation capacity available to meet expected summer demand levels since last year. Second, the effects of the economic recession will likely persist through the summer and lower the peak demand for electricity. These two factors lead to higher calculated reserve margins, which are even higher than the expected levels for 2009 when the effects of the recession were first experienced in California. [2] The higher planning reserve margins lead to a lower probability that emergency conditions will occur this summer, not counting unpredictable catastrophic events, such as the April 4, 2010, earthquake in Baja California or the extremely high temperatures that rarely occur but happened in 2006.

Supply

Between last summer and June 1, 2010, 1,234 megawatts (MW) of new generation have either been added or are expected to be added to the state's supply.[3] The major generation

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1. The report does not include either an evaluation of the condition of the electricity market, specific contractual details, or the adequacy of any individual utility or local distribution systems.

2. The likelihood of having adequate supplies is increased with a 15 to 17 percent "buffer" of electricity supplies above expected peak demand, which are available to call upon as needed. This "buffer" target is referred to as a *planning reserve margin*. A planning reserve margin defines the minimum level of electricity supplies needed to cover a range of unexpected contingencies, such as increased air conditioning demand on a hotter-than-average day or an unplanned maintenance event at a power plant. Planning reserve margin targets are calculated using average peak demand conditions.

3. California Independent System Operator's *2010 Summer Loads and Resource Operations Preparedness Assessment* issued May 10, 2010, states that the California ISO system has added, or will add by June 1, 2010, 1,760 MW of capacity. Most of the disparity is because California ISO added 520 MW the Blythe Energy Project Phase II project as a new resource because the project changed interconnection to the California ISO's control area this year. This resource has been operating since 2003 and has always been counted (at 560 MW) in the Energy Commission's Summer Outlooks. The remainder of the difference is due to counting conventions (such as 70 MW versus 6 MW for the retirement of the DOW Chemical power plant in Pittsburg) and projects that Energy Commission staff did not include because confirmation of operational status could not be confirmed.

retirements over the same period were the South Bay Units 3 and 4 in the San Diego area (397 MW) and Calpine's power plant at the Dow Chemical facility in Pittsburg (70 MW), totaling a loss of 467 MW. The result is a net addition of 767 MW of generation statewide. Additions and retirement of generation resources are discussed in **Appendix A**.

Demand

In the near term, the greatest uncertainty in the peak demand forecast is weather-related; air conditioning loads increase rapidly as temperatures rise. To characterize the range of possible demands under varying temperatures, staff used the analysis of peak demand response to temperature prepared for the *2009 Integrated Energy Policy Report* demand forecast.[4] The 1-in-2 demand forecast represents expected demand at temperatures with a 50 percent probability of being exceeded due to hotter-than-average weather. The 1-in-2 temperature conditions are based on the distribution of the annual maximum temperatures experienced in each area since 1950. The 1-in-10 peak demand forecast assumes temperatures at the 90th percentile of the historical annual peak temperature distribution and has a 10 percent probability of being exceeded.

The statewide annual maximum 1-in-2 peak demand forecast is about 1 percent (830 MW) below the *Summer 2009 Electricity Supply and Demand Outlook* forecast for last summer, reflecting the continued effects of the recession. The maximum 1-in-10 forecast is slightly higher than the 2009 1-in-10 forecast because the high temperature multipliers prepared for the *IEPR* forecast are higher than in the previous forecast. These higher multipliers offset the decrease in demand from economic effects. The 1-in-2 statewide 2010 peak demand forecast is about 4 percent higher than the actual 2009 peak, in part because of summer 2009 maximum temperatures that were below 1-in-2 levels, but also because of the severity of the recession in 2009.

Additional Factors

A slight increase in the combined voluntary demand response and interruptible program forecast contributes to the planning reserve margin difference from 2009. Utility demand response programs available within the California ISO have increased by 350 MW, consistent with the goal of the *Energy Action Plan* to increase price-responsive demand and rely less on interruptible load. Accordingly, these increases are partially offset by a 270 MW decline in interruptible programs. Demand response resources in other balancing areas inside the state increased by 100 MW over the *2009 Outlook*. Some of this increase reflects improved reporting in *2009 IEPR* data submitted by utilities on their demand response efforts.

4. California Energy Commission. December 2009. *California Energy Demand 2010 – 2020 Commission-Adopted Forecast*, CEC-200-2009-012-CMF.

Adequate hydroelectric generation capacity is expected to be available to meet peak power needs, despite three consecutive dry years and runoff being below average this past winter and spring. The late spring snowpack is above average, and indications are that hydroelectric energy production during the summer and fall months will be close to average. Capacity supplies are expected to be adequate for all peak demand periods.

Reserve Margins

Statewide electricity reserve margins for 2010 are shown in **Table 1**. They range from 28 to 43 percent, fluctuating each summer month under normal summer temperature conditions (1-in 2), exceeding the planning reserve margin target by at least 11 percent in all months. The margins under unusually hot summer weather conditions range from 17 to 31 percent. For comparison, the estimated planning reserve margins in the *2009 Outlook Report* were from 23 to 35 percent under normal weather conditions, and from 16 to 22 percent under unusually hot conditions.[5] With these margins, there should be sufficient resources to cover most system contingencies, including high demand due to hotter-than-normal (1-in-10 year probability) weather conditions.

Table 1: Statewide 2010 Summer Outlook (MW)

Resource Adequacy Planning Conventions		June	July	August	September
1	Existing Generation (Note 1)	61,029	61,044	61,060	61,100
2	Expected Retirements (Note 2)	0	0	0	0
3	Expected Additions (Note 2)	15	16	40	0
4	Net Imports (Note 3)	13,118	13,118	13,118	13,118
5	Total Net Generation	74,162	74,178	74,218	74,218
6a	Interruptible / Curtailable Programs	1,497	1,738	1,679	1,776
6b	Demand Response (DR)	1,073	1,091	1,105	1,138
7	Total Net Supply	76,733	77,007	77,001	77,132
8	Expected 1-in-2 Normal Summer Temperature Demand	54,098	58,704	60,797	55,414
8a	**Reserve Margin (1-in-2 Demand)**	**43%**	**32%**	**28%**	**40%**
9	Expected 1-in-10 Unusually Hot Summer Temperature Demand	58,734	63,745	65,965	60,197
9a	**Reserve Margin (1-in-10 Demand)**	**31%**	**21%**	**17%**	**28%**

Source: Energy Commission staff

Notes: 1) Existing generation includes capacity either actually added or retired, or expected to be added or retired, between August 1, 2009, and May 31, 2010.
2) See Table 6, "Additions and Retirements for Summer 2010," and its discussion for detailed information.
3) Net import equals imports into California minus exports. This is also referred to as net interchange.

Probability Assessment of Operating Reserve Margins

In addition to planning reserve margins, a second measure of system adequacy is the operating reserve margin used by the California ISO.[6] Dropping below a specified operating

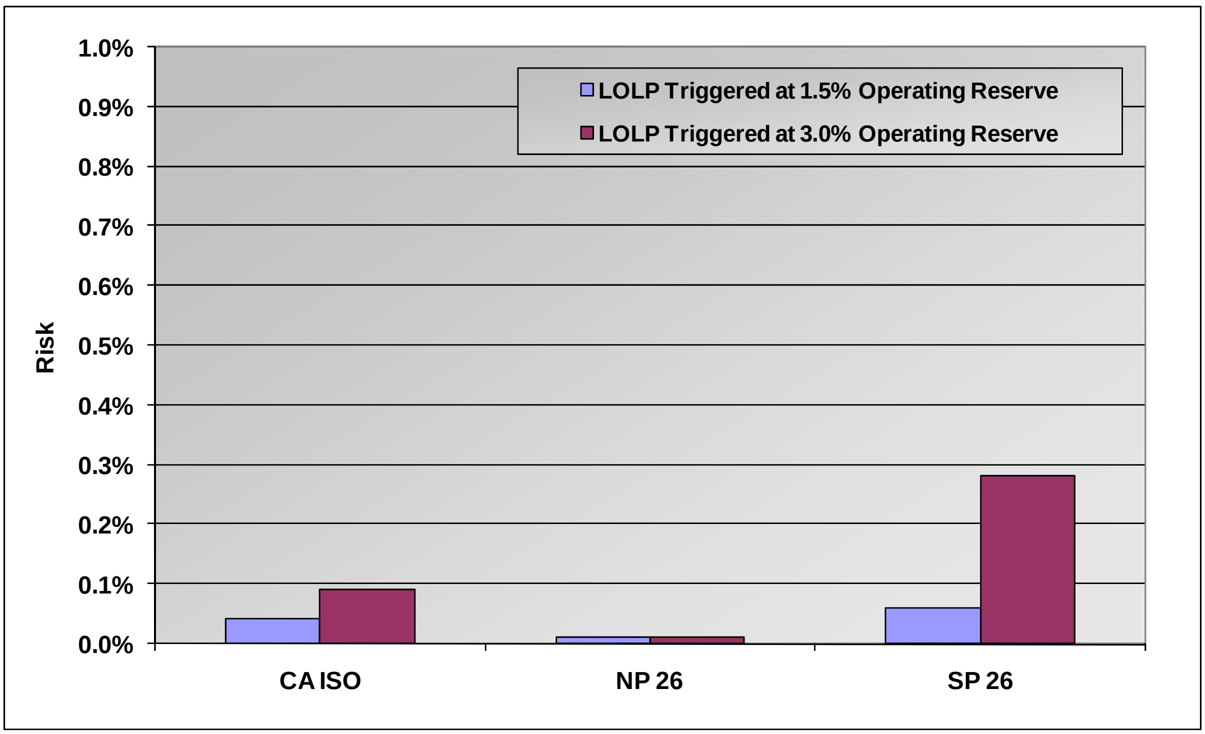
5. *Summer 2009 Electricity Supply and Demand Outlook* (*2009 Outlook*) Table 1: California 2008 Summer Outlook (MW), p. 2.

6. Operating reserve margin is the amount of imports and actual spinning generation above current demand and represents real-time operations that fluctuate minute by minute.

reserve margin threshold will require additional purchases of power and calls for demand response and voluntary interruptible programs to avoid the possibility of uncontrolled outages that can cascade throughout the West. The California ISO calls warning stages at 7 percent (Stage 1) and 5 percent (Stage 2) operating reserves. A Stage 3 Emergency is triggered when operating reserves fall to a level between 3 and 1.5 percent, depending on the specific operating conditions.

The southern portion of the California ISO, covering most of Southern California, has a 0.28 percent probability of experiencing a Stage 3 Emergency this summer on the peak day. The California ISO Balancing Authority Area, as a whole, and its northern subregion have a probability of rotating outages of less than one-tenth of 1 percent (0.10 percent) (**Figure 1)**.

Figure 1: Loss of Load Probability



Source: Energy Commission staff

A probability cannot be expressed for a California total because the statewide system is composed of multiple balancing areas and does not operate as a single system. While this assessment covers electricity generation and the large interconnected transmission system, it does not include possible failures within local distribution systems.

Further, utilities outside the California ISO Balancing Authority Area (BAA) operate as separate systems and have insufficient data availability with which to conduct probabilistic assessments. Nonetheless, staff communications suggest that such utilities have adequate resources to meet expected electricity demand this summer. These public utilities include

Los Angeles Department of Water and Power , Burbank Water and Power, Glendale Water and Power, and Imperial Irrigation District in Southern California and Sacramento Municipal Utility District, Modesto Irrigation District, Redding, Roseville Electric, and Turlock Irrigation District in Northern California.

2010 Summer Supply and Demand Outlook

This outlook examines four regions — statewide, the California ISO Balancing Authority Area overall, and California ISO's system in the northern and southern part of the state:

- The statewide region includes the major investor-owned and municipal utilities in the state.
- The California ISO BAA is divided into Northern and Southern California subregions because there are transmission constraints south of the transmission segment, known as Path 26, that limit the transfer of electricity from north to south. The two subregions are referred to as NP 26 ("North of Path 26") and SP 26 ("South of Path 26"). The combination of the two subregions is referred herein as the California ISO region.
- The NP 26 region includes the Pacific Gas and Electric (PG&E) service area and the participating municipal utilities and energy service providers (ESPs) in Northern California served by the California ISO.
- The SP 26 region includes Southern California Edison (SCE), San Diego Gas & Electric (SDG&E), Southern California municipal utilities, and ESPs that participate in the California ISO system.

The *2010 Outlook* summarizes a deterministic assessment (a single point forecast) of expected peak demand, electricity imports, and in-state generation reserves under average and hotter-than-normal summer conditions.[7] The *2010 Outlook* also includes a probabilistic assessment (ranges of possible outcomes) to evaluate the cumulative risks of generation and transmission outages under variant peak demand levels. This assessment evaluates the likelihood that California may experience low operating (real-time) reserve margins and involuntary outages. The statewide outlook is presented only in a deterministic format because the electricity system is comprised of multiple balancing areas and does not operate as a single entity, making probabilities for outages nearly impossible to estimate.

7. The *2010 Outlook* is based on forecasted loads documented in California Energy Commission, December 2009, *California Energy Demand 2010 – 2020 Commission-Adopted Forecast*, CEC-200-2009-012-CMF.

Regional Reserve Margins

Table 2 through **Table 5** provide the estimated reserve margins for each of the four regions using demand projections under two types of weather conditions, the average summer conditions referred to as the "1-in-2" conditions, and the hotter, more adverse weather conditions known as "1-in-10" conditions. For the entire summer of 2010, the reserve margins for all regions under 1-in-2 weather conditions are expected to be higher than the target 15 percent planning reserve margin, with the lowest being 27 percent in SP 26 during August. Last year, the lowest calculated reserve margin was 26 percent in SP 26 during August. These reserve margins indicate there should be more-than-sufficient resources to cover a range of other system contingencies, such as unplanned facility outages or higher-than-expected demand due to hot weather conditions. Under 1-in-10 weather conditions, the lowest reserve margin is expected to be 16 percent for SP 26 in August. In 2009, the value was 13 percent in SP 26 during August.

Table 2: Statewide 2010 Summer Outlook (MW)

	Resource Adequacy Planning Conventions	June	July	August	September
1	Existing Generation (Note 1)	61,029	61,044	61,060	61,100
2	Expected Retirements (Note 2)	0	0	0	0
3	Expected Additions (Note 2)	15	16	40	0
4	Net Imports (Note 3)	13,118	13,118	13,118	13,118
5	Total Net Generation	74,162	74,178	74,218	74,218
6a	Interruptible / Curtailable Programs	1,497	1,738	1,679	1,776
6b	Demand Response (DR)	1,073	1,091	1,105	1,138
7	Total Net Supply	76,733	77,007	77,001	77,132
8	Expected 1-in-2 Normal Summer Temperature Demand	54,098	58,704	60,797	55,414
8a	**Reserve Margin (1-in-2 Demand)**	**43%**	**32%**	**28%**	**40%**
9	Expected 1-in-10 Unusually Hot Summer Temperature Demand	58,734	63,745	65,965	60,197
9a	**Reserve Margin (1-in-10 Demand)**	**31%**	**21%**	**17%**	**28%**

Source: Energy Commission staff

Notes: 1) Existing generation includes capacity either actually added or retired, or expected to be added or retired, between August 1, 2009, and May 31, 2010.

2) See Table 6, "Additions and Retirements for Summer 2010," and its discussion for detailed information.

3) Net import equals imports into California minus exports. This is also referred to as *net interchange*.

Table 3: California ISO 2010 Summer Outlook (MW)

	Resource Adequacy Planning Conventions	June	July	August	September
1	Existing Generation (Note 1)	49,470	49,470	49,470	49,510
2	Expected Retirements (Note 2)	0	0	0	0
3	Expected Additions (Note 2)	0	0	40	0
4	Net Imports (Note 3)	10,350	10,350	10,350	10,350
5	Total Net Generation	59,820	59,820	59,860	59,860
6a	Interruptible / Curtailable Programs	1,497	1,738	1,679	1,776
6b	Demand Response (DR)	760	775	789	825
7	Total Net Supply	62,078	62,334	62,328	62,462
8	Expected 1-in-2 Normal Summer Temperature Demand	43,271	46,646	48,497	44,124
8a	**Reserve Margin (1-in-2 Demand)**	**43%**	**34%**	**29%**	**42%**
9	Expected 1-in-10 Unusually Hot Summer Temperature Demand	46,952	50,620	52,601	47,908
9a	**Reserve Margin (1-in-10 Demand)**	**32%**	**23%**	**18%**	**30%**

Source: Energy Commission staff

Notes: 1) Existing generation includes capacity either actually added or retired, or expected to be added or retired, between August 1, 2009, and May 31, 2010.

2) See Table 6, "Additions and Retirements for Summer 2010," and its discussion for detailed information.

3) Net import equals imports into California minus exports. This is also referred to as *net interchange*.

Table 4: NP 26 California ISO 2010 Summer Outlook (MW)

	Resource Adequacy Planning Conventions	June	July	August	September
1	Existing Generation (Note 1)	25,795	25,795	25,795	25,795
2	Expected Retirements (Note 2)	0	0	0	0
3	Expected Additions (Note 2)	0	0	0	0
4	Net Imports (Note 3)	1,750	1,750	1,750	1,750
5	Total Net Generation	27,545	27,545	27,545	27,545
6a	Interruptible / Curtailable Programs	297	302	323	319
6b	Demand Response (DR)	394	400	415	442
7	Total Net Supply	28,236	28,246	28,283	28,306
8	Expected 1-in-2 Normal Summer Temperature Demand	20,432	21,694	21,649	19,463
8a	**Reserve Margin (1-in-2 Demand)**	**38%**	**30%**	**31%**	**45%**
9	Expected 1-in-10 Unusually Hot Summer Temperature Demand	21,923	23,278	23,230	20,884
9a	**Reserve Margin (1-in-10 Demand)**	**29%**	**21%**	**22%**	**36%**

Source: Energy Commission staff

Notes: 1) Existing generation includes capacity either actually added or retired, or expected to be added or retired, between August 1, 2009, and May 31, 2010.

2) See Table 6, "Additions and Retirements for Summer 2010," and its discussion for detailed information.

3) Net import equals imports into California minus exports. This is also referred to as *net interchange*.

Table 5: SP 26 California ISO 2010 Summer Outlook (MW)

Resource Adequacy Planning Conventions		June	July	August	September
1	Existing Generation (Note 1)	23,675	23,675	23,675	23,715
2	Expected Retirements (Note 2)	0	0	0	0
3	Expected Additions (Note 2)	0	0	40	0
4	Net Imports (Note 3)	10,100	10,100	10,100	10,100
5	Total Net Generation	33,775	33,775	33,815	33,815
6a	Interruptible / Curtailable Programs	1,200	1,436	1,355	1,457
6b	Demand Response (DR)	366	376	374	383
7	Total Net Supply	35,342	35,588	35,545	35,656
8	Expected 1-in-2 Normal Summer Temperature Demand	23,904	26,099	27,995	25,746
8a	**Reserve Margin (1-in-2 Demand)**	**48%**	**36%**	**27%**	**38%**
9	Expected 1-in-10 Unusually Hot Summer Temperature Demand	26,142	28,543	30,617	28,158
9a	**Reserve Margin (1-in-10 Demand)**	**35%**	**25%**	**16%**	**27%**

Source: Energy Commission staff

Notes: 1) Existing generation includes capacity either actually added or retired, or expected to be added or retired, between August 1, 2009, and May 31, 2010.

2) See Table 6, "Additions and Retirements for Summer 2010," and its discussion for detailed information.

3) Net import equals imports into California minus exports. This is also referred to as *net interchange*.

Table 6 lists the dependable capacity of all generation additions and retirements included in the *2010 Outlook*. These are additions and retirements that occurred since August 31, 2009, or that are believed to have a high probability of taking place before August 1, 2010. The statewide totals include 1,234 MW of capacity added and 467 MW retired during the time frame, for a net addition of 767 MW. See **Appendix A** for a detailed presentation of additions and retirements.

The net imports assumption represents a conservative estimate of potential electricity imports into each region, based on the western system's capability to provide surplus generation during peak demand periods. This interconnected, interdependent wholesale power market provides reliability support and broad cost reduction benefits. The Pacific Northwest and the Desert Southwest regions have a diverse mix of surplus electricity resources and different load patterns, which create opportunities for the Pacific Northwest and Desert Southwest regions to sell electricity to California during the summer season. California also sells electricity to the Pacific Northwest during the regional winter peak season.

Table 6: Additions and Retirements for Summer 2010

Additions / Retirements[1]	Capacity Added or Retired (MW)	Date
CA ISO SP 26		
Additions		
Sierra Sun Tower (solar thermal)	4	8/5/2009
Otay Mesa Energy Center (combined-cycle)	608	10/3/2009
Chino RT Solar Project (solar PV)	2	11/10/2009
Blythe Solar 1 (solar PV)	17	11/14/2009
Toland Landfill (landfill gas)	1	11/18/2009
Ormat North Brawley GeoThermal (ORNI 18)	17	2/9/2010
Orange Grove Energy (simple-cycle)	96	4/31/2010
Inland Empire (combined-cycle, Unit 2 + STG)	400	5/3/2010
Olivehain Pumped Storage (2 units @ 20 MW ea.)	40	8/1/2010
Additions Sub-Total	1,184	
Retirements		
South Bay Units 3 and 4	-397	12/31/2009
Retirements Sub-Total	-397	
Total CA ISO SP 26	***787***	
CA ISO NP 26		
Additions		
Vaca-Dixon (solar PV)	2	12/31/2009
Cal RENEW (solar PV)	5	4/10/2010
Additions Sub-Total	7	
Retirements		
Calpine DOW Chemical Pittsburg	-70	3/5/2010
Retirements Sub-Total	-70	
Total CA ISO NP 26	***-63***	
Total CA ISO	**724**	
Los Angeles Dept. of Water & Power (LADWP)		
Additions		
Pine Tree (wind)	12	12/31/2009
Additions Sub-Total	12	
Retirements		
None	0	NA
Retirements Sub-Total	0	
Total LADWP	**12**	
Imperial Irrigation District (IID)		
Additions		
GreenHunter Biomass	15	6/30/2010
Additions Sub-Total	15	
Retirements		
None	0	NA
Retirements Sub-Total	0	
Total IID	**15**	
Sacramento Municipal Utility District		
Buena Vista Biomass	16	7/1/2010
Additions Sub-Total	16	
Retirements		
None	0	NA
Retirements Sub-Total	0	
Total SMUD	**16**	
Statewide Additions	1,234	
Statewide Retirements	-467	
Total Statewide	**767**	

Source: Energy Commission staff

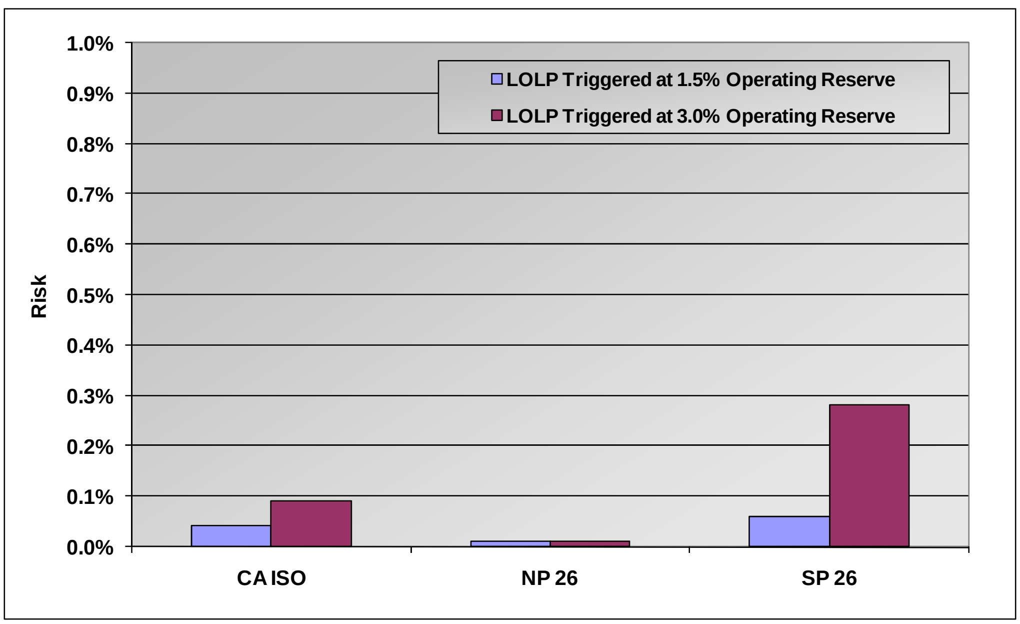
[1]Solar is credited at 80 percent of nameplate capacity and wind at 10 percent. All other additions are at 93 percent of nameplate. The capacity for South Bay Units 2 and 3 are Net Qualifying Capacities from the California ISO.

Probability Assessments

Figure 2 displays the estimates of the probability of involuntary load curtailment within the California ISO BAA and the two subregions at the peak hour for the summer 2010 period. To maintain the Western Electricity Coordinating Council (WECC) Minimum Operating Reserve Criteria, the California ISO continuously recalculates the operating reserve margin and will declare a Stage 3 Emergency when reserves fall to a level between 1.5 and 3 percent, depending on the current system operating conditions.[8] The California ISO can initiate rotating customer curtailments under a Stage 3 Emergency to ensure that the system remains stable and avoid the possibility of uncontrolled outages that can cascade throughout the West.

The loss of load probability (LOLP) estimates for both the low and high range operating reserve margins (1.5 and 3 percent, respectively) have been included in **Figure 2.** The actual LOLP would likely fall within the range between the two points estimated. The SP 26 region has the highest probability of involuntary load curtailment or rotating outages. The corresponding LOLP estimates for the region are between 0.06 and 0.28 percent. The California ISO BAA and NP 26 both have an expected LOLP of less than one-tenth of 1 percent (0.10 percent) for summer 2010.

Figure 2: Loss of Load Probability



Source: Energy Commission staff

8. The operating reserve margin does not include the generation that is not scheduled to operate, shut down for planned maintenance, unexpected failure outages, or unable to be delivered due to transmission issues. Actual demand levels may also be higher than expected when generation was scheduled to operate the day before and result in a shortfall in operating power plant supply.

Regional Probabilistic Assessments

Planning reserve margins are a long-term metric intended to assure sufficient electricity supplies can meet real-time operating reserve requirements and maintain a 1-in-10 year loss of load probability reliability target. The deterministic reserve margin calculations are suitable to evaluate whether each region within California falls within the planning reserve margin targets. This type of assessment, however, does not consider the probability of various system fluctuations occurring, nor the variability with which they occur. For example, it is possible that several generators could simultaneously fail and cause a decrease in operating reserves, but the deterministic assessment will not give an indication of the cumulative likelihood of this or other system emergency events. A statistical assessment of different system variables is necessary to evaluate the risks of realizing lower operating reserve levels. The probability assessment provides a more rigorous evaluation of the system risks compared to deterministic calculations of operating reserves.

The staff continues to employ a reasonably detailed probabilistic assessment of the electricity system to enhance the deterministic tables provided in previous reports. The deterministic tables presented in previous outlooks included estimated reserve margins for two operating scenarios: peak demand during average weather conditions (1-in-2) and hotter than expected (1-in-10) conditions. In system planning, however, neither supply nor demand can be predicted with absolute accuracy or determined by a single point forecast. Future conditions that determine load, as well as availability of supply, can be better characterized as falling within a range of uncertainty. Studies based only upon the most likely set of conditions fall short of looking at the full range of possible demand levels and the fluctuation in supply capabilities. Likewise, studies based on adverse conditions are still limited in scope and may overestimate the exposed risk to these events.

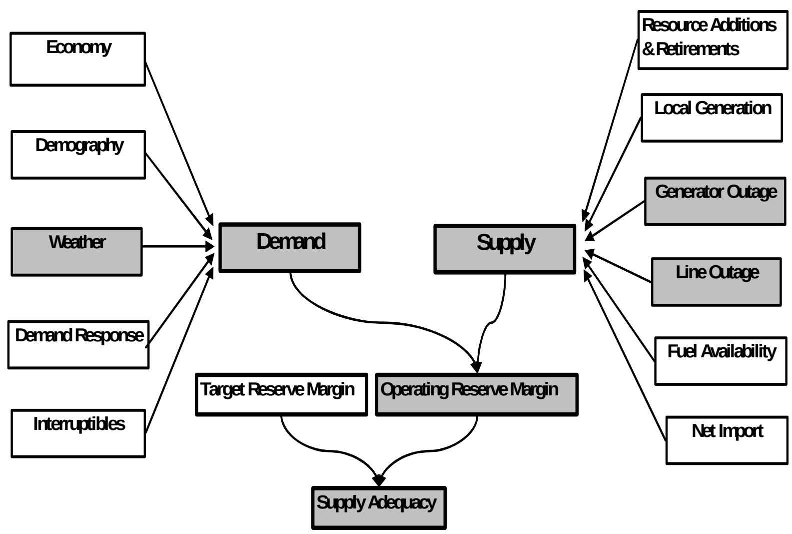
As the high loads experienced during the extended heat wave of the summer of 2006 illustrated, actual peak demand can be significantly higher than projected in the hotter-than-normal (1-in-10) forecast, and the consequences will therefore not be captured by a deterministic method. This experience demonstrated the limitations of single- or two-point deterministic evaluations. Evaluating a wider range of factors and future conditions affecting supply adequacy to cover unexpected contingencies provides greater insight into the possible risks to supply adequacy.

The observed performance of the electricity system over time and an extensive record of temperature conditions that are correlated to actual demand have allowed the Energy Commission staff to develop probability of occurrence measures for several of the major uncertainty factors. Incorporating the probability of occurrence to an electricity supply assessment provides a better representation of the fluctuations in the system and measures the risks of actually encountering an electric system emergency event based on historical data.

The Supply Adequacy Model (SAM) is a forecasting tool that assesses the balance of power supply and demand for a power system throughout the WECC regions. SAM was originally developed at the Energy Commission in 1998. For this analysis, the staff employed a modified version of the SAM to analyze a specific region. This modified version of the SAM is referred to as SAM-A. The SAM-A was designed to be a relatively fast and simple analytical tool with the capability of incorporating uncertainty variables. The probabilistic approach for analyzing supply adequacy is an important feature of SAM-A, which differs from deterministic models.

There are a number of variables to consider when assessing supply adequacy of a system. This probabilistic assessment evaluates the complete range of demand scenarios based on weather variation, as well as generation and transmission outage occurrences based on historical data. The staff developed multiple cases of different resource availability, transmission capabilities and demand-varying scenarios using the Monte Carlo method to determine physical supply adequacy.[9] **Figure 3** shows the major factors used to develop the 2010 outlook. The probabilistic method was applied to the factors in the highlighted boxes in the chart.

Figure 3: Major Factors Affecting Supply Adequacy



Source: Energy Commission Staff

9. The Monte Carlo Method is a means of simulating a complex, "real world" system using a computer model. The method provides a means of reasonably estimating the likelihood certain results of a random event, such as the tossing of a game die, will occur. The computer model can provide many "tosses" in a short period of time, providing a means of estimating "distributions of outcomes," or the likelihood certain results will occur, in the complex system.

The following description explains how the probabilistic method was applied, focusing on the analysis of the SP 26 region. The analytical process is the same for all three regions, but SP 26 was selected for illustration because it has the highest risk of firm load curtailments.

Probability of Demand

In the near term, the greatest factor introducing uncertainty in the peak load forecast is weather. The 1-in-2 demand forecast represents expected demand at average temperatures; there is a 50 percent probability that the forecast will be exceeded due to hotter-than-normal weather. To characterize the range of possible demands under varying temperatures, staff used the analysis of peak demand response to temperature prepared for the *2009 IEPR* demand forecast.[10]

The staff method for assessing the demand-temperature relationship is documented in previous reports.[11] Generally, linear regression is used to estimate the effect of a change in temperature on peak demand. Staff used 2008 hourly load data from the California ISO and utility area daily temperatures to estimate the relationship between summer weekday afternoon peaks and temperatures. The estimation included days from June 15 through September 15 on which the weighted average maximum temperature was above 75 degrees in the SCE area or 70 degrees in the SDG&E area.

The temperature variables for each area are weighted average temperatures from weather stations representative of the climate in that particular region. Because residential air conditioning is the primary driver of day-to-day changes in peak demand, weather station weights are based on the estimated number of residential air conditioning units in each of the utility forecast zones in the Energy Commission's residential demand forecast model.

Peak electricity demand does not always occur in the hottest day of the year. There is a strong correlation between peak electricity demand and a build-up of high temperatures over several days. To capture this effect, different weather variables are calculated that best correlate with demand in a given region. For SP 26, two weather variables are used. The first is a weighted average of maximum temperatures for three days. This weighting consists of 60 percent of the current day's maximum temperature, 30 percent of the previous day's maximum temperature, and 10 percent of the second previous day's maximum temperature. This lag is used to account for heat buildup over a three-day period. The daily minimum temperature is the second temperature variable. It serves as a proxy measure of daily humidity and also captures the effect of lack of nighttime cooling on peak demand. For NP 26, one variable is calculated as the weighted average of the daily maximum and

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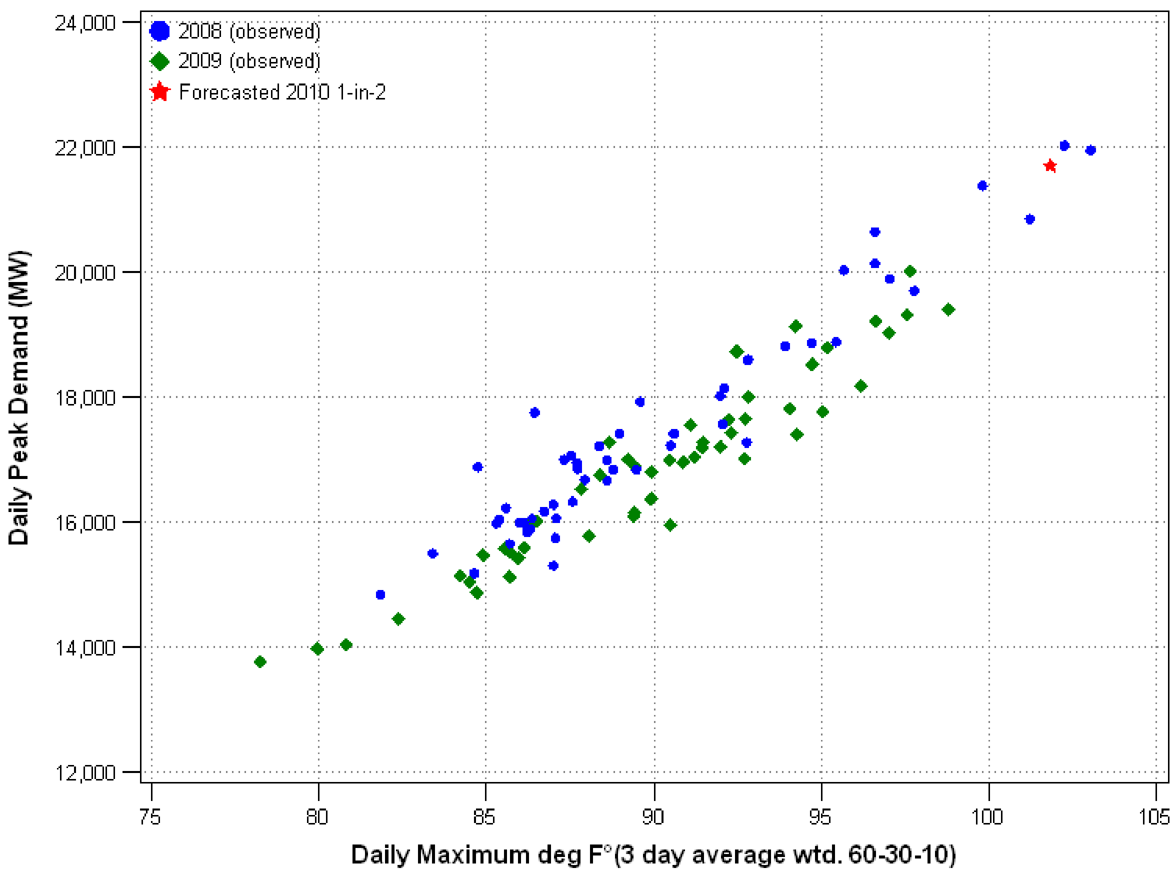
10. California Energy Commission. December 2009. *California Energy Demand Commission-Adopted Forecast 2010 - 2020*, CEC-200-2009-012-CMF.

11. California Energy Commission. June 2007. *Staff Forecast of 2008 Peak Demand*, CEC-400-2007-006-SF.

daily minimum temperature, weighted 61 percent and 39 percent respectively. In comparisons of predicted versus actual summer peak demands in NP 26, this weather variable consistently outperformed others over the last several years.

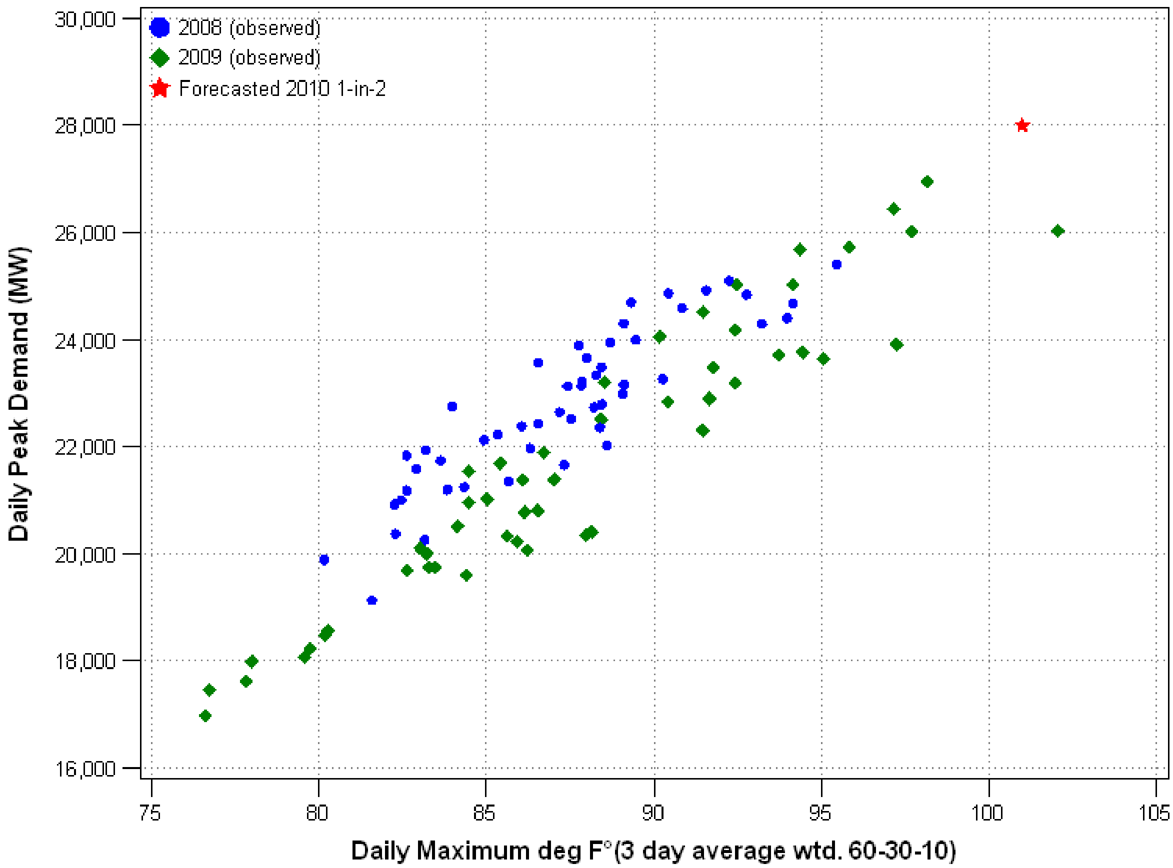
Figure 4 and **Figure 5** plot the observed relationship between temperatures and loads in summer 2008 and 2009, plus the forecasted 1-in-2 peak demand for 2010 in NP 26 and SP 26 respectively. For comparability, both regions are plotted against the three-day-weighted-average statistic. A 1 degree increase in weighted average temperature equates to a 310 MW increase in peak demand in NP 26. The estimated temperature response for 2009 is slightly lower, although the lack of hot days in 2009 makes this less certain. In SP 26, the temperature response for 2008 was 350 MW per degree. The estimated response in 2009 was 390 MW; 2008 estimates are used for consistency with the adopted forecast.

Figure 4: NP 26 2008 and 2009 Loads Versus Temperature



Source: Energy Commission

Figure 5: SP 26 Loads Versus Temperature



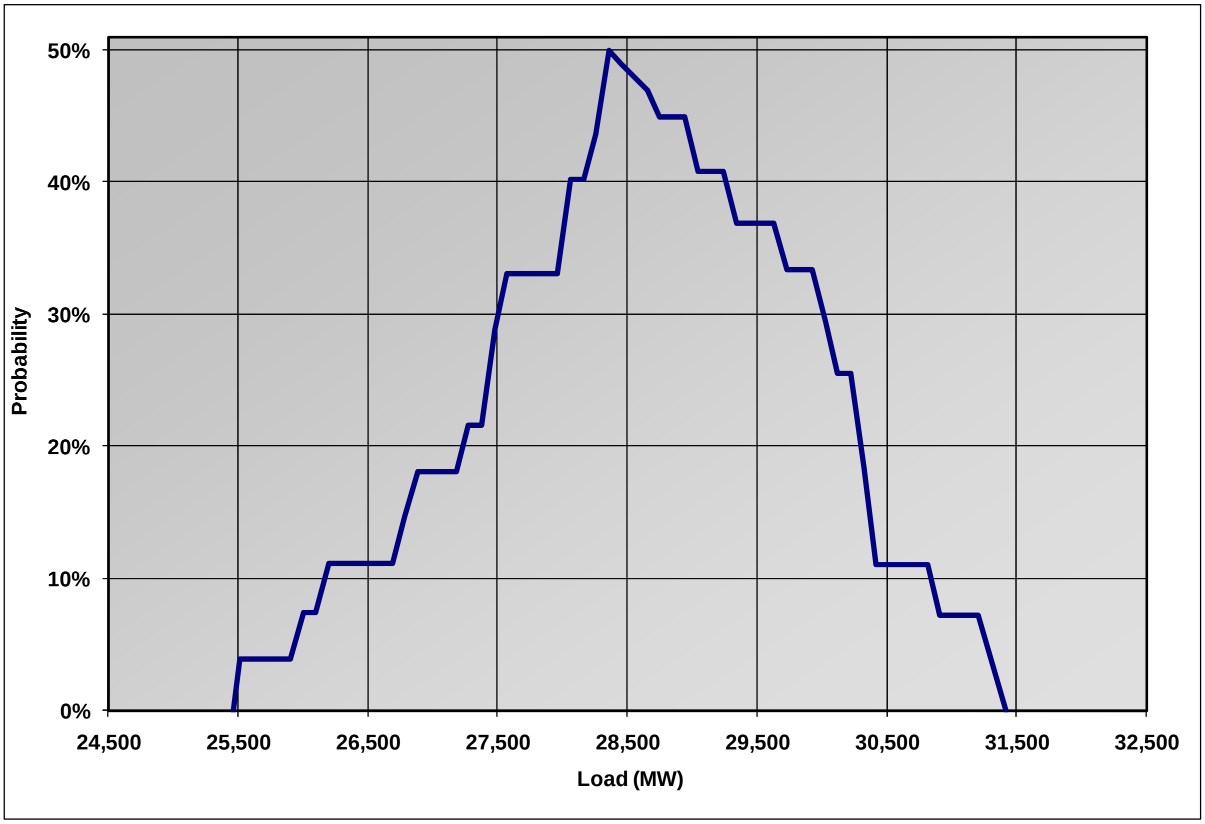
Source: Energy Commission

To derive expected peak demand at various temperatures, the estimated coefficients are applied to 58 years of historic daily temperatures to calculate predicted annual maximum peak demands. The 58 years of predicted annual peaks provide a distribution of possible peak demands under the weather conditions that have been observed since 1950. The mean and standard deviation of this distribution are used to construct a one-tailed confidence interval that indicates the expected demand at various points on a normal distribution. The mean of the predicted annual peaks is the weather-normalized, "1-in-2," peak demand. Peak demand at the 90^{th} percentile is the 1-in-10 peak demand.

To calculate a set of summer 2010 peak demand possibilities, staff applied the estimated peak demand distribution to the 2010 1-in-2 peak demand forecast. For example, if the 2010 1-in-2 demand forecast for SP 26 is 2 percent higher than weather-normalized 2008 1-in-2 peak demand, the temperature-load distribution is scaled up by 2 percent. The SAM model uses this distribution to generate a set of possible outcomes. The resulting loads and their probabilities for SP 26 are presented in **Figure 6**.

Figure 6 shows that the range of demand in SP 26 during 2010 could be as low as 25,102 MW or as high as 31,198 MW with a "most likely" demand of 27,958 MW. While the forecast could equally be higher or lower than the mean, the risks associated with the higher options are more relevant for planning considerations.

Figure 6: Probability of Demand California ISO SP 26 Summer 2010



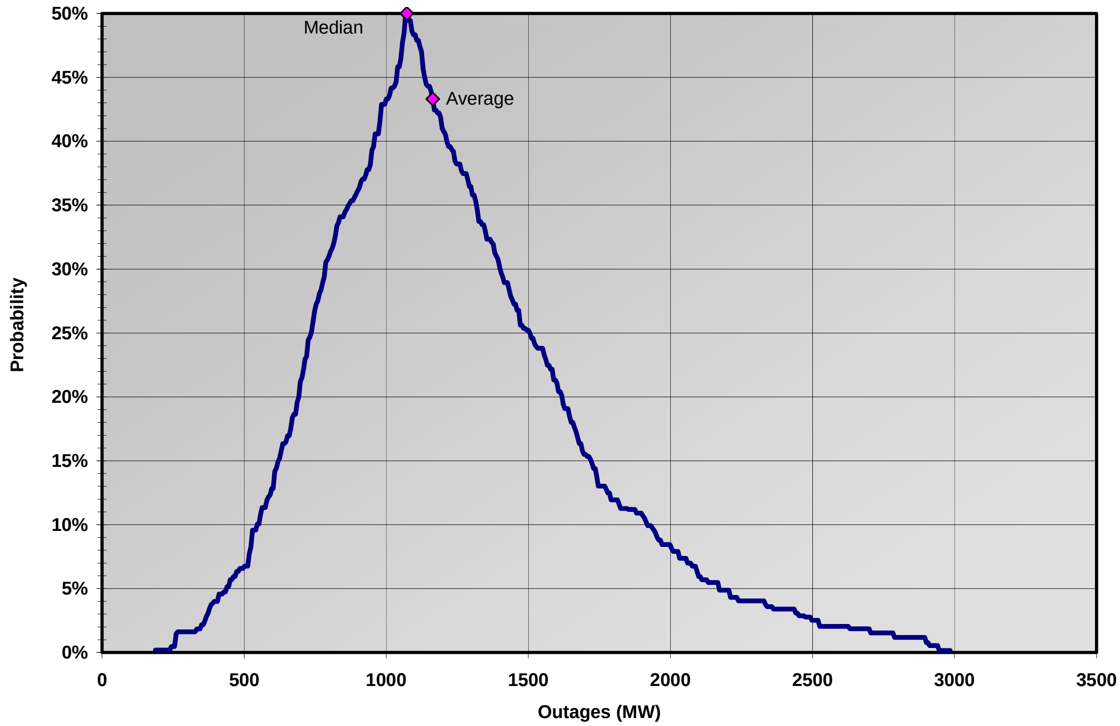
Source: Energy Commission staff

Probability of Generation-Forced Outages

Similar to the impact and range of possible demand, the magnitude of the total available resources can be expected to fall within a range of uncertainty due to the variation in forced outages. The Energy Commission staff calculated potential 2010 outages using actual 2002 through 2007 daily outage totals for the summer peak period provided by the California ISO. This set of data was statistically processed, and the results are presented in **Figure 7**.

Figure 7 shows the range of SP 26 forced outages in 2010 could be as low as 185 MW or as high as 2,990 MW, with a "most likely" outage outcome of 1,070 MW. Again, the risks associated with the higher outages are the more relevant factors for resource planning considerations. Staff estimates a 10 percent probability that forced outages will be as high as 1,915 MW and a 3 percent probability that they will be as high as 2,450 MW.

Figure 7: Probability of Generation Forced Outages California ISO SP 26 Summer 2010



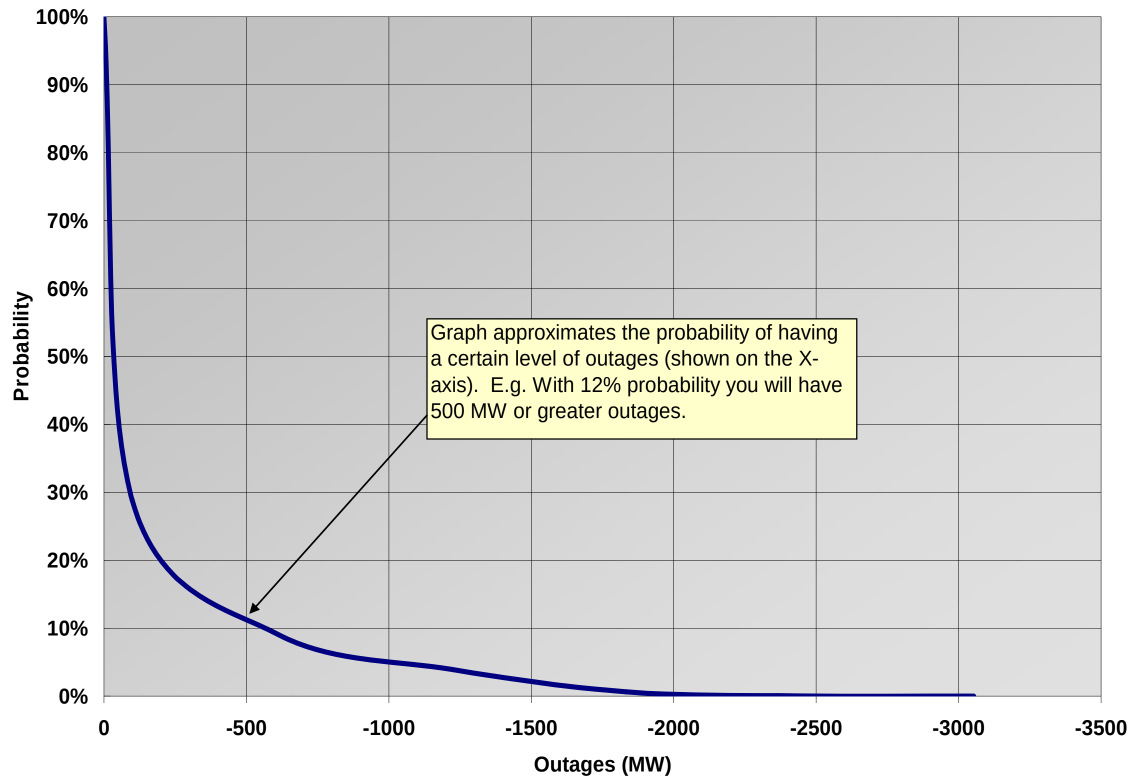
Source: Energy Commission staff

Probability of Transmission Line Forced Outages

A major transmission line outage can also have significant impacts on the overall operation of the system. These outages often occur with little or no warning and, in the case of the Pacific DC Intertie (PDCI), can account for as much as a 2,000 MW reduction in resources available to meet load. On August 25, 2005, the PDCI unexpectedly dropped out of service just as Southern California was approaching its daily peak load. This outage, coupled with a 2,000 MW deviation in the day-ahead peak demand forecast, required the California ISO to issue a Transmission Emergency notice requesting utilities in SP 26 to reduce demand by curtailing 900 MW of firm load and 800 MW of voluntary interruptible load for about 35 minutes.

The staff included the effects of major transmission outages in the probabilistic analysis for this report. To calculate the overall impact of these failures on the SP 26 region, the staff used data obtained via subpoena from the California ISO to compare hourly transfer capacities with the WECC rating for each transmission line. One limitation of using this method is that it may omit short duration outages that are not visible at the time the transfer capacity is reported. For example, a line that drops out of service at five minutes after the hour and is restored 50 minutes later would not be visible in the dataset. **Figure 8** provides the range of transmission outages observed from May 15 through September 15 for 2003 through 2006.

Figure 8: Probability of Transmission Line Forced Outages California ISO SP 26 Summer 2010



Source: Energy Commission staff

Probability of Maintaining Minimum Required Operating Reserves

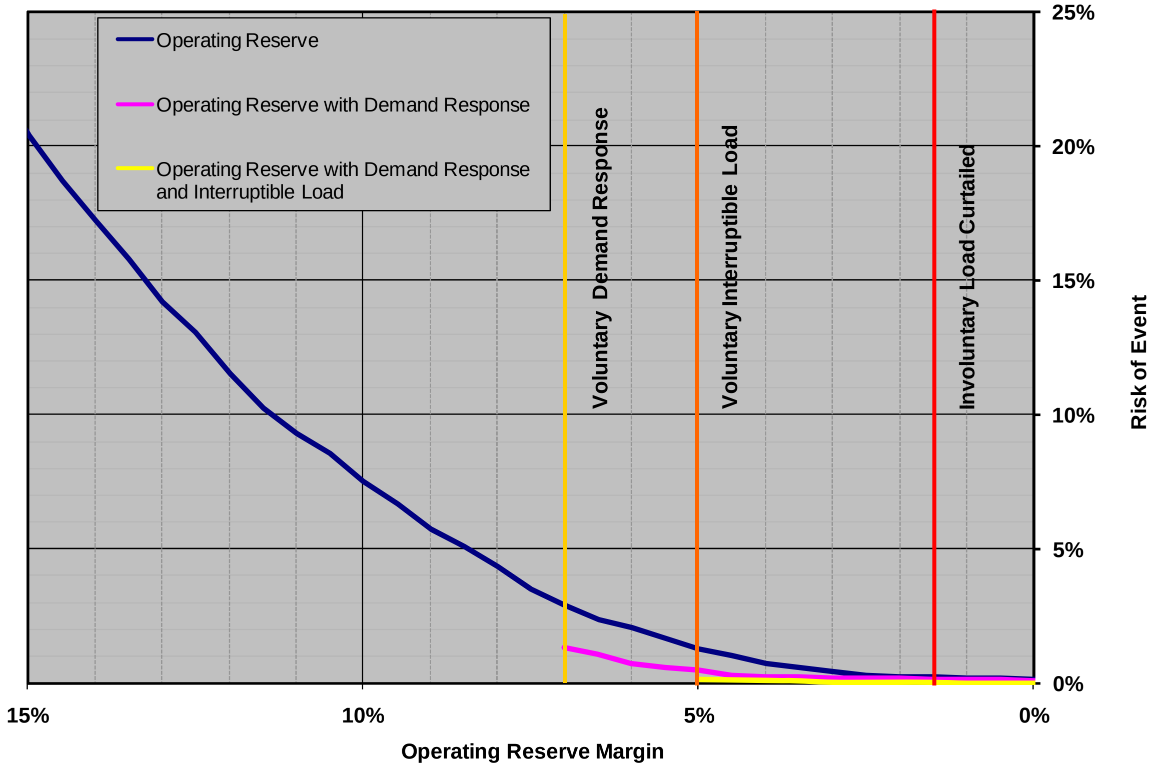
Calculating generation and transmission availability and comparing the sum against a complete range of electricity demand result in a probabilistic assessment of resource adequacy. Using the Monte Carlo method, 5,000 cases of different resource and demand scenarios are developed for summer 2010. Each case is then reviewed to determine whether resources are sufficient to meet demand plus minimum operating reserves. The SAM-A model conducts the calculations in the following four major steps:

- Using Monte Carlo draws, the model generates a deterministic case of input data in which each uncertainty factor takes a random value from its respective range of possible values.
- Evaluation of the adequacy of supply is made for each deterministic case using spreadsheet tables.

- The above steps are repeated for multiple cases to reasonably cover all possible combinations of the values of the uncertain factors.
- The resulting set of cases is statistically processed to calculate:
  - The probability that there is insufficient capacity to meet the peak demand and maintain a given reserve margin.
  - The probability that there is sufficient capacity to meet the peak demand and maintain a given reserve margin.

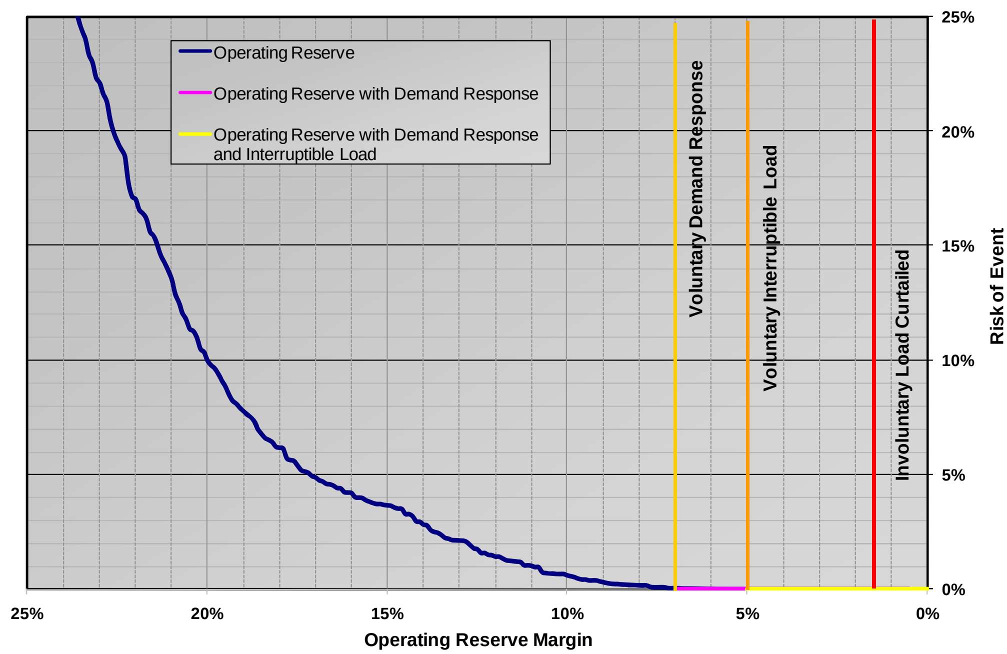
Figure 9, **Figure 10**, and **Figure 11** provide the probabilities for dropping to the minimum operating reserve margin levels for each of the three studied regions.

Figure 9: Operating Reserve – California ISO Summer 2010



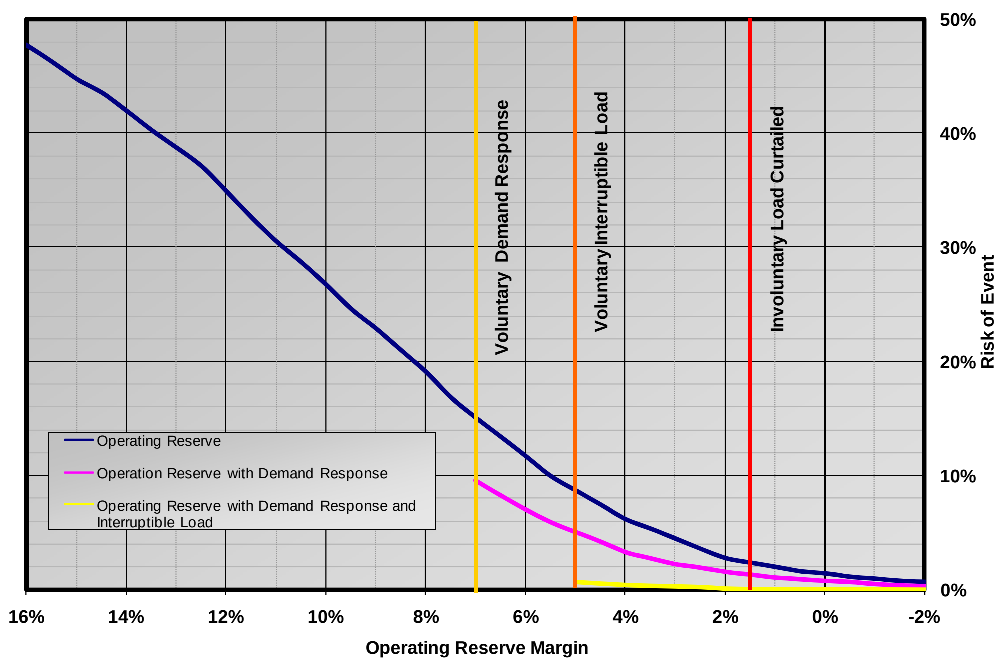
Source: Energy Commission staff

Figure 10: Operating Reserve – California ISO NP 26 Summer 2010



Source: Energy Commission staff

Figure 11: Operating Reserve – California ISO SP 26 Summer 2010

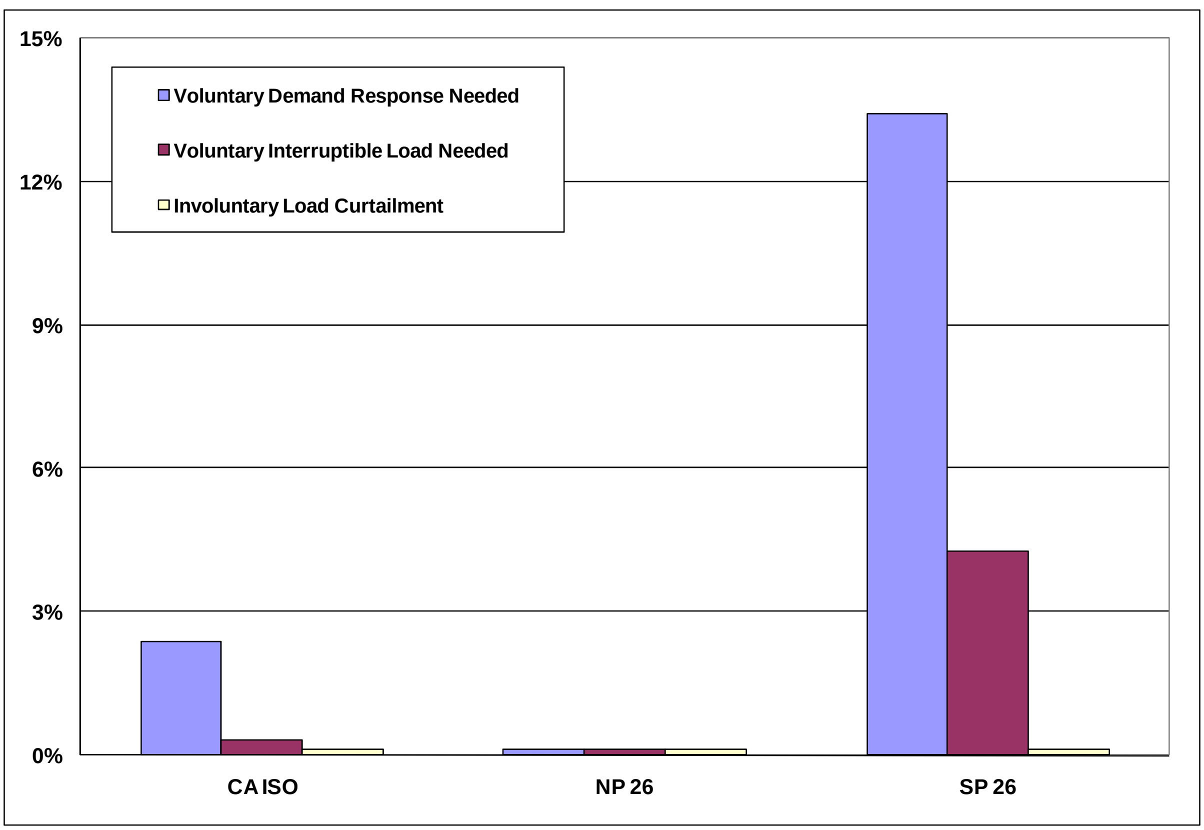


Source: Energy Commission staff

Figure 12 provides a close-up of the critical points identified in **Figures 9 through 11** for each of the three regions on the peak day of summer 2010. These results also can be interpreted in terms of event risk. The staff assessment shows very low risks of involuntary load curtailments (low end of Stage 3 Emergency alert, 1.5 percent operating reserves) in each of the assessed regions. The staff also completed separate risk calculations for operating reserve margins dropping to 3 percent (high end of Stage 3 Emergency alert) and found the SP 26 probability of events increased to 0.25 percent, from less than one-tenth of 1 percent. The probability of events for the California ISO and NP 26 at the 3 percent reserve margin levels remained very low, each below 0.1 percent. The risk of curtailing firm load in the SP 26 region is now on par with the same risk measures for the other analyzed regions, namely each of these risks are less than one-half of one percent for any analyzed measure of Stage 3 firm load curtailment. Collectively, these event risks appear likely to remain very low in the near term.

The likelihood of using voluntary demand response and interruptible load programs is substantially higher in SP 26. This may be considered an acceptable risk level since the customers enrolled in these programs receive preferential rates or other incentives to provide an extra level of mitigation during peak load conditions.

Figure 12: Risk of Event on the Summer 2010 Peak Day



Source: Energy Commission staff

Glossary

Acronym	Definition
AFC	application for certification
BAA	Balancing Authority Area
CEC	California Energy Commission
California Independent System Operator	California ISO
CPUC	California Public Utilities Commission
ESP	energy service provider
IEPR	*Integrated Energy Policy Report*
IOU	investor-owned utility
LADWP	Los Angeles Department of Water & Power
LOLP	loss of load probability
MW	megawatt
MORC	minimum operating reserve criteria
NQC	net qualifying capacity
NERC	North American Electric Reliability Council
NP 26	North of Path 26
PDCI	Pacific DC intertie
PG&E	Pacific Gas and Electric
QF	qualifying facility
SAM	Supply adequacy model
SP 26	South of Path 26
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
WALC	Western Area Lower Colorado
WECC	Western Electricity Coordinating Council

APPENDIX A: Detailed Assumptions Used to Calculate Planning Reserve Margins

The Energy Commission studies potential long-term (10 years) electricity supply and demand conditions to ensure that California maintains a sustainable and reliable energy system into the future. The Energy Commission also analyzes short-term market developments and a range of potential system variations to determine if there are any significant risks of potential supply shortfalls during the upcoming peak demand season. This analytical activity became particularly important following the 2000-2001 energy crisis experiences.

For a small number of hours, the generation capacity that sits idle for most of the year is needed to meet peak demand. Electricity use varies widely over the time of day and time of year. On a typical day, demand increases 60 percent from the midnight low to the afternoon high. Because air conditioning loads drive peak demand, California sees its greatest demand spikes during the summer months (June, July, August, and September). On a hot summer day, this swing can be 85 - 90 percent. The difference in demand between an average summer day and a very hot peak day is 6 percent. This difference is equivalent to three years' average growth in statewide electricity demand. This variable demand trend requires a generation system that is extremely flexible. The full available capacity of the system needs to be dispatched only to meet a few hours of peak demand each summer.

The electricity supply assessment for the summer peak demand season includes evaluating existing reserves that serve as a buffer for unplanned fluctuations, and analyzing the probabilities that a system emergency may occur. A reserve margin is a measure of the amount of electricity imports and in-state generation capacity available over average peak demand conditions. Reserve margins are measured at two levels: planning and operating.

A specified *planning* reserve margin target is the level necessary to cover a particular range of possible system fluctuations and unexpected emergencies. The target is based on the possibility that a loss of load would occur no more frequently that one day in 10 years, which translates into a 15 to 17 percent planning reserve margin. Rare conditions will occur, such as the 2006 summer temperatures that caused a simultaneous spike in electricity demand throughout California and the West. Even though this 1-in-30 year event topped out above the range of uncertainties established for the planning reserve margin target, sufficient electricity imports and generation supplies avoided any customer curtailments.

A planning reserve margin that is too low may result in a higher chance of customer curtailments. A target reserve margin that is too high may dampen generation and transmission investment incentives, cost more than consumers are willing to pay for the risk of an outage, and frustrate new development (including renewables and demand response) that depends on evolving regulatory decisions. Increasing the planning reserve margin to cover a larger range of contingencies would require more generation and transmission facilities to be built which could stand idle until the rare event occurs. The goal is to balance the risks of outages and overall costs to maintaining a redundant system.

An *operating* reserve margin is the amount of imports and actual ("spinning") generation above current demand, and represents real-time operations that fluctuate minute to minute.[12] The operating margin is the target buffer that is assumed to be sufficient for control area operators to deal with immediate emergencies or fluctuations in electricity demand, such as hotter than predicted day-ahead temperatures, and/or generation, such as unplanned maintenance. The regional North American Electric Reliability Councils (NERC) establishes Minimum Operating Reserve Criteria (MORC) that is necessary to maintain system reliability. The Western Electricity Coordinating Council is the regional body that evaluates the MORC levels for all West Coast system operators.

The minimum operating reserve criteria target is approximately 7 percent but varies depending on the portfolio mix of generation resources. To be counted as part of the operating reserves, conventional generation facilities must be ready to generate electricity when needed. Hydro-generation systems require only a 5 percent operating reserve target since these facilities can generate electricity on a moment's notice. Electricity imports are usually backed up by the operating reserves within the source region.

Factors Used to Determine Planning Reserve Margins

Table A-1 thru **Table A-7** provide a more detailed description of the data and assumptions used to calculate the planning reserve margin in the *Summer 2010 Electricity Supply and Demand Outlook*.

Existing Generation

Existing generation accounts for thermal and hydro generation facilities operational as of August 31, 2009, plus new generation either already online or expected to be online prior to June 1, 2010. Thermal generation consists of California ISO control area merchant and municipal thermal resources (including non-hydro renewable), investor-owned utility (IOU) retained generation,[13] and qualifying facilities (QFs). Merchant thermal generation capacity

12. This does not include the generation that is not scheduled to operate, shut down for planned maintenance, unexpected failure outages, or unable to be delivered due to transmission problems. Actual demand levels may also be higher than expected when generation was scheduled to operate the day before and result in a shortfall in operating power plant supply.

13. Retained generation include the facilities that were not sold by the IOUs when the California electricity market was restructured in the late-1990s.

in SP 26 includes 1,080 MW of contracted capacity from units located in Baja California Norte.

Thermal unit capacity is derated to reflect summer operating conditions, and this summer derating can range from 90 to 96 percent of nameplate capacity based on the type of unit considered and its geographic location. The derated value is termed "dependable capacity." The Non-California ISO generation totals include both thermal and hydro capacity. **Table A-1** shows additions and retirement of generation capacity since September 1, 2009, and that expected to be added by June 1, 2010.

Table A-1: 2010 Derated Generation (MW)

	South	North	Total
CA ISO Control Area			
As of 31 Aug 09: Thermal, QF and RE[1]	21,880	19,510	41,390
As of 31 Aug 09: Hydro[2]	1,049	5,951	7,000
Total CA ISO as of 31 Aug 09	**22,929**	**25,461**	**48,390**
Non-CA ISO as of 31 Aug 09	6,555	4,996	11,551
Statewide Total as of 31 Aug 09			**59,941**
CA ISO Control Area			
Added between 01 Sep 09 & 31 May 10: Thermal, QF and RE[1]	1,067	7	1,074
Retired between 01 Sep 09 & 31 May 10: Thermal, QF and RE[1]	-397	0	-397
Added between 01 Sep 09 & 31 May 10: Hydro[2]	0	0	0
Retired between 01 Sep 09 & 31 May 10: Hydro[2]	0	0	0
Total CA ISO Added or Retired between 01 Sep 09 & 31 May 10	670	7	677
Net Non-CA ISO Added or Retired between 01 Sep 09 & 31 May 10	12	0	12
Statewide Total Added or Retired between 01 Sep 09 & 31 May 10			**689**
CA ISO Control Area			
As of 01 Jun 10: Thermal, QF and RE[1]	22,550	19,517	42,067
As of 01 Jun 10: Hydro[2]	1,049	5,951	7,000
Total CA ISO as of 01 Jun 10	**23,599**	**25,468**	**49,067**
Non-CA ISO as of 01 Jun 10	6,567	4,996	11,563
Statewide Total as of 01 Jun 10			**60,630**

Source: Energy Commission staff

[1]Derated capacities for existing thermal, QF and renewable resources that are neither wind nor solar are California ISO Net Qualifying Capacities (NQC). (NQC Local Area Data for Compliance Year 2010 – Final, http://www.caiso.com/23a4/23a4aec6183d0ex.html.) Derated capacities for new resources of these types are 93 percent of nameplate. Wind generation is credited at 10% of nameplate and solar at 80%.

[2]Statewide minimum derated hydroelectric capacity is at least 7,000 MW. See the discussion, Hydroelectric Dependable Capacity below. North and South have been allocated as 15% and 85%, respectively, based on the amounts shown in the *Summer 2009 Electricity Supply and Demand Outlook*, Table A-1, p. A-3.

Hydroelectric Dependable Capacity

Every year there is at least 7,000 MW of dependable generating capacity from hydroelectric resources in California to meet peak system loads in the California ISO BAA. This is a conservative number based on an analysis of dry year conditions expected to occur, on average, once in every five years. This conclusion is supported by physical systems assessment, by historical performance, and by utilities' resource supply plan filings to the Energy Commission. These supply plans demonstrate that utilities have adequate resources to serve peak summer loads based on 1-in-5 hydrological conditions.

This 1-in-5 dry year criteria is built into the resource adequacy counting conventions for net qualifying capacity (NQC). Other criteria include the capability to generate during four consecutive hours for three consecutive days. These counting criteria are reasonable, prudent, and reliable for predicting the dependability of the resources for serving peak loads.

In addition, two California ISO information sources support the conclusion that at least 7,000 MW is always available to utilities in the California ISO BAA from hydroelectric facilities located inside this balancing area. The California ISO regularly updates and Web-publishes a Master Control Area Generating Capability List.[14] As of February 2, 2010, total net dependable capacity for 225 listed hydro units was 9,320 MW. Electrical studies have shown these hydro units have a maximum simultaneous deliverability rating of 8,766 MW.

For system and local reliability purposes, most of the larger hydro units have been rated for NQC. The NQC values are used by load serving entities to demonstrate (year ahead and month ahead) that they have procured adequate capacity resources to meet forecasted peak loads. For compliance year 2010, final NQC Local Area Data were published on October 29, 2009.[15] For some hydro units, generally smaller in size, a single NQC number applies to all months. For these 185 hydro units, the total year-round NQC value is 2,373 MW. Other hydro units have monthly NQC values because many are high elevation facilities that do not operate during the winter because of icing, or are supplied by reservoirs where fluctuating lake levels lead to small changes in gross head pressure to turbines, which affect generator output capacity. Monthly NQC capacities are summarized in **Table A-2**.

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14. http://www.caiso.com/14d4/14d4c4ff59780.html

15. http://www.caiso.com/1796/179688b22c970.html

Table A-2: Net Qualifying Capacity for Hydro Units in California ISO

	By Month	Year-Round	Total
Jan	5,307	2,373	7,680
Feb	5,336	2,373	7,709
Mar	5,495	2,373	7,868
Apr	5,572	2,373	7,945
May	5,678	2,373	8,051
Jun	5,709	2,373	8,082
Jul	5,678	2,373	8,051
Aug	5,605	2,373	7,978
Sep	5,494	2,373	7,867
Oct	5,411	2,373	7,784
Nov	5,401	2,373	7,774
Dec	5,387	2,373	7,760

Source: Energy Commission staff

Thus, from **Table A-2**, the lowest total NQC for hydro is 7,680 MW in January. During June through September, the lowest total NQC value for hydro is 7,867 MW in September. These totals do not include hydroelectric generation owned by Western Area Power Administration, such as 380 MW New Melones or 80 MW Parker in California or 600-plus MW available to Southern California utilities from Hoover Dam in Nevada. Nor does it include 402 MW from Hetch Hetchy power plants controlled by the city and county of San Francisco that the California ISO rates as net dependable capacity, but which is not obligated by regulatory requirements to serve loads in the California ISO.

Another metric supports the conclusion that at least 7,000 MW is dependably available to utilities in the California ISO. In early 2009, on resource supply plans submitted to the Energy Commission for the *2009 IEPR*, these utilities forecast hydro capacity in 2010 would total 7,261 MW.

Generating performance of these resources during the two-year extreme drought in 1976–1977 and the six-year extended drought from 1987 to 1992 shows that an additional planning derate to 6,900 MW could be considered possible, but a derate to 6,500 MW or less for these resources would not be a warranted assumption.

The 6,989 MW of available capacity that is included in **Table A-2** does not include “imports” delivered to the California ISO by the Western Area Power Administration supported by their portfolio of Central Valley Project hydro plants at Lake Shasta, Trinity Reservoir, Folsom Lake, New Melones, and elsewhere.

Dependable hydro capacity at peak does not significantly change between wet and dry water years even though the historical record shows that dry conditions can have a significant impact on available energy production. In California, hydroelectric generating capacity is not significantly diminished (or derated) when less water is available. Most of the capacity at utility hydroelectric powerhouses is located far below dams and river diversion points, making these resources relatively immune to seasonally fluctuating reservoir levels. Water from high elevation reservoirs is typically delivered to these power plants by flumes, tunnels, and then penstocks to power plants at a much lower elevation, sometimes hundreds of feet below in a distant canyon. Where utility power plants are located at a dam site, most utility-managed reservoirs are kept full to meet daily, weekly, and annual peak loads.

Electric utilities have decades of experience managing snowmelt runoff to ensure adequate fuel water will be available to meet annual peak summer loads. At most hydropower facilities in California, water is dependably delivered to each powerhouse when it is most valuable. This, combined with at least 7,000 MW of dependable generating capacity from hydroelectric resources in California to meet peak system loads in the California ISO BAA, leads staff to conclude that there is sufficient hydropower capacity available even during periods of extreme reductions in water supplies.

Generation Additions and Retirements

Table A-3 lists the dependable capacity of all additions and retirements included in the *2010 Outlook*. These are additions and retirements having occurred either since September 1, 2009, or are believed to have a high probability of taking place by August 31, 2010. The statewide aggregate totals 1,234 MW of capacity added and 467 MW retired during the time frame, for a net addition of 767 MW.

Table A-3: Additions and Retirements for Summer 2010 (MW)

Additions / Retirements[1]	Capacity Added or Retired (MW)	Date
CA ISO SP 26		
Additions		
Sierra Sun Tower (solar thermal)	4	8/5/2009
Otay Mesa Energy Center (combined-cycle)	608	10/3/2009
Chino RT Solar Project (solar PV)	2	11/10/2009
Blythe Solar 1 (solar PV)	17	11/14/2009
Toland Landfill (landfill gas)	1	11/18/2009
Ormat North Brawley GeoThermal (ORNI 18)	17	2/9/2010
Orange Grove Energy (simple-cycle)	96	4/31/2010
Inland Empire (combined-cycle, Unit 2 + STG)	400	5/3/2010
Olivehain Pumped Storage (2 units @ 20 MW ea.)	40	8/1/2010
Additions Sub-Total	1,184	
Retirements		
South Bay Units 3 and 4	-397	12/31/2009
Retirements Sub-Total	-397	
Total CA ISO SP 26	***787***	
CA ISO NP 26		
Additions		
Vaca-Dixon (solar PV)	2	12/31/2009
Cal RENEW (solar PV)	5	4/10/2010
Additions Sub-Total	7	
Retirements		
Calpine DOW Chemical Pittsburg	-70	3/5/2010
Retirements Sub-Total	-70	
Total CA ISO NP 26	***-63***	
Total CA ISO	**724**	
Los Angeles Dept. of Water & Power (LADWP)		
Additions		
Pine Tree (wind)	12	12/31/2009
Additions Sub-Total	12	
Retirements		
None	0	NA
Retirements Sub-Total	0	
Total LADWP	**12**	
Imperial Irrigation District (IID)		
Additions		
GreenHunter Biomass	15	6/30/2010
Additions Sub-Total	15	
Retirements		
None	0	NA
Retirements Sub-Total	0	
Total IID	**15**	
Sacramento Municipal Utility District		
Buena Vista Biomass	16	7/1/2010
Additions Sub-Total	16	
Retirements		
None	0	NA
Retirements Sub-Total	0	
Total SMUD	**16**	
Statewide Additions	1,234	
Statewide Retirements	-467	
Total Statewide	**767**	

Source: Energy Commission staff

[1] Solar is credited at 80 percent of nameplate capacity and wind at 10 percent. All other additions are at 93 percent of nameplate. The capacity for South Bay Units 2 and 3 are net qualifying capacities from the California ISO.

Newly Operational, Delayed, Cancelled, Changed, or Retired Generation

Numerous changes to the state's electricity generation fleet have occurred since August 1, 2009. These include additions of new generation, one large retirement, and some delays of generation resources that were expected to be contributing by the summer of 2010.[16]

Resources Added or Expected by End of the Summer of 2010

Thirteen generation resources have either been added since the *2009 Outlook* or are expected to be added before the end of the summer of 2010. These are listed below by either California ISO subregion or non-California ISO areas.

California Independent System Operator's SP 26 Subregion[17]

Eight generating projects have been added since August 1, 2009[18]:

- Sierra SunTower, a 5 MW solar thermal project near Lancaster, Los Angeles County, achieved commercial operations on August 5, 2009.[19]
- Otay Mesa Energy Center , a 608 MW natural gas-fired combined cycle project located in San Diego County achieved commercial operations on October 3, 2009. Its capacity increases from 590 MW to 608 MW when its "peaking" capability is used. Staff used the 608 MW value for the summer period because this is when the additional capacity is expected to be employed.[20]

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16. August 1, 2009, is used rather than September 1, 2009, because the Sierra Sun Tower project was not included in the *2009 Outlook*.

17 As of mid-April 2010, six small projects in the California Independent System Operator's control area were in the development stage but were not included because staff could not determine whether they would achieve operational status. They are: Chiquita Canyon Landfill (9 MW), Rialto RT Solar (2 MW) and El Cajon Energy Center (46 MW), all in SP 26; and, Blue Lake Biomass (12 MW), Big Creek Water Works (5 MW), and Copper Mountain Solar 1 (8 MW) in NP 26. If all of these projects achieve operational status during the summer, reserve margins would increase by less than one percent.

18 The California Independent System Operator issued it's *2010 Summer Loads and Resources Operations Preparedness Assessment* on May 10, 2010, showing the Blythe Energy Project Phase II adding 520 MW (NQC) to the system by June 1, 2010. (http://www.caiso.com/2793/2793ae4d395f2.pdf The Assessment, Table 5, p. 11, accessed May 24, 2010.) This project is the existing operating Florida Power and Light (Nextera Energy) resource that has been operating since 2003, connecting to Western Area Power Administration's Western Area Lower Colorado system. The interconnection was changed to the California ISO's system in early May 2010. Generation from this plant has been added into the Energy Commission's resources since that time; therefore, it is not considered as new generation in this report. This plant is *not* the Caithness Energy (Terra Gen Power) Blythe Energy Project Phase II that was licensed by the Energy Commission on December 14, 2005. Construction of the Caithness plant has not begun, and the plant is not expected until 2013. (Email from Robert Emmert, California ISO staff to Marc Pryor, Energy Commission staff, April 15, 2010.)

19. *Clean Technia* article (http://cleantechnica.com/2009/08/10/esolar-officially-launches-californias-sierra-suntower-plant/, accessed February 17, 2010).

20. Calpine Corporation (http://www.calpine.com/power/ accessed January 11, 2010).

- Chino RT Solar Project, a 2 MW solar photovoltaic project near Chino, San Bernardino County, came on-line November 10, 2009.[21]
- Blythe Solar 1, a 21 MW (17 MW net) solar photovoltaic project near Blythe, Riverside County, came on-line on November 14, 2009.[22]
- Toland Landfill, a 1 MW landfill gas project in Ventura County, started producing power on November 18, 2009.[23]
- Ormat's North Brawley ORNI-18 project, a 17 MW geothermal plant near Brawley in Imperial County, came on-line on February 9, 2010.[24]
- Orange Grove Energy, a 96 MW natural gas-fired simple cycle project located in San Diego County, achieved commercial operations in April 2010.[25]
- Inland Empire Energy Center's remaining capacity of 400 MW started contributing to the grid on May 3, 2010. As discussed in the *2009 Outlook*, this plant experienced equipment failure in 2009 that delayed the on-line date of the combustion turbine Unit 2 and its associated steam turbine generator. This plant is located near Romoland in Riverside County.

California Independent System Operator's NP 26 Sub-Area

One small solar photovoltaic project came on-line at the end of 2009, and another came on-line in April 2010.

- The Vaca-Dixon project is a 2 MW project came on-line on December 31, 2009.
- The CalRENEW project is a 5 MW project that came on-line in April 2010.

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21. California Independent System Operator (www.caiso.com/2457/2457b09622680.xls, accessed February 17, 2010).

22. *Renewable Energy World* article (http://www.renewableenergyworld.com/rea/news/article/2009/12/first-solar-nrg-energy-open-21-mw-blythe-project, accessed February 17, 2010).

23. Ventura Regional Sanitation District (http://www.vrsd.com/news.htm, accessed 2/16/10).

24. Although operational in December 2009, the nominal 50 MW Ormat geothermal plant is experiencing difficulties generating more than 17 MW due to the exceptional amount of undissolved solids in the geothermal fluid. The plant is not expected to reach full capacity until the end of the year. Therefore, Energy Commission staff is using the 17 MW capacity value for summer 2010. (Source: http://www.greenjobs.com/Public/IndustryNews/inews07411.htm, accessed February 17, 2010.)

25. Source: Energy Commission, compliance project manager.

Non-California ISO Area

Los Angeles Department of Water and Power (LADWP) added one wind project in 2009. Imperial Irrigation District (IID) and Sacramento Municipal Utility District (SMUD) are expected to start taking deliveries from projects during the summer.

- LADWP's 12 MW Pine Tree Wind project started delivering power on December 31, 2009. It is located in Kern County north of Mojave.
- IID is expected to start taking deliveries from the 15 MW GreenHunter biomass plant near El Centro, Imperial County, on June 30, 2010.
- SMUD is expected to start taking deliveries from the 16 MW Buena Vista biomass plant near Lodi, San Joaquin County, on July 30, 2010.

Retirements Effected or Expected by End of the Summer of 2010

California Independent System Operator's SP 26 SubRegion

Two of the five units of the South Bay power plant in Chula Vista, San Diego County, were retired on or before December 31, 2009. These are Units 3 and 4 (175 MW and 222 MW, respectively).

Retirement of these units occurred for two reasons. First, the Otay Mesa Energy Center achieved commercial operations, thus allowing the California Independent System Operator to release the units from a "Reliability Must Run" status[26]. This in turn allowed the San Diego Regional Water Quality Control Board to modify South Bay's National Pollution Discharge Elimination System permit for the plant, requiring Unit 3 and 4 to cease operations by December 31, 2009.[27]

California Independent System Operator's NP 26 Subregion[28]

- Calpine's 70 MW power plant at the Dow Chemical facility in Pittsburg was shut down in March 2010. The facility is now served by the 550 MW Los Medanos Energy Center

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26. Reliability Must Run is a contractual condition imposed by the California ISO on a power plant that ensure system reliability. This includes generation that is required to meet the reliability criteria for interconnected systems operation, needed to meet load (demand) in constrained areas and provide voltage or security support of the California ISO or of a local area, or both.

27. The Board's decision was based on the California Independent System Operator's decision that Units 3 and 4 were no longer required for "Reliability Must Run" reasons. [http://www.waterboards.ca.gov/sandiego/board_decisions/adopted_orders/2009/R9_2009_0178_ratification.pdf. The California ISO letter is cited in the Board's adopted order, amendment p. 1. Accessed February 1, 2010.]

28. The Trans Bay Cable was expected to enable retirement of Mirant's 206 MW Potrero Unit 3 power plant in San Francisco sometime before to the end of the summer, but as of April 20, 2010, this is no longer the situation.

Non-California ISO Areas

There were no retirements in non-California ISO areas.

Delays, Cancellations, Withdrawals, Suspensions, and Denials

California Independent System Operator's SP 26 Subregion

- In the *2009 Outlook*, staff noted that SCE's proposed 44 MW Mandalay (McGrath) Peaker Unit Project in Oxnard had been delayed because of Coastal Commission concerns and had been dropped from listing for 2009. This was despite the Coastal Commission approving the project during March 2009.[29] On December 14, 2009, a Los Angeles Superior Court judge rejected SCE's request that an injunction be issued against the city of Oxnard preventing the city from enforcing its water policy.[30] Therefore, the status of this project is still undetermined.
- On June 2, 2009, the developer of San Gabriel Generating Station, RRI Energy Inc. (formerly Reliant Energy, Inc.), filed a motion with the Energy Commission for the suspension of its application for certification (AFC) (07-AFC-2) citing the lack of air quality emissions reduction credits in the South Coast Air Basin. The Energy Commission suspended the San Gabriel Generating Station on June 5, 2009. On December 1, 2009, RRI Energy Inc. requested an extension of the suspension, and on December 10, 2009, the Energy Commission granted an extension with an expiration date of June 1, 2010.[31] The proposed project was to have been a 696 MW natural gas-fired combined cycle power plant in Rancho Cucamonga, San Bernardino County.
- On June 9, 2009, the developer of the Highgrove Power Plant Project filed with the Energy Commission a motion for the suspension of its AFC (06-AFC-2) citing the lack of air quality emissions reduction credits in the South Coast Air Basin. The Energy Commission granted the suspension on July 31, 2009. On February 2, 2010, AES Highgrove, LLC filed for termination of AFC. The Energy Commission terminated the project on February 4, 2010. The proposed project was to have been a 300 MW natural gas-fired peaking power plant in the city of Grand Terrace, San Bernardino County.[32]

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29. *Summer 2009 Electricity Supply and Demand Outlook, p. A-6.*

30. News article, *"Edison peaker plant at Mandalay held," iStockAnalyst*, December 15, 2009. http://www.istockanalyst.com/article/viewiStockNews/articleid/3713602, accessed January 6, 2010.

31. California Energy Commission, *Energy Facility Status* listing, updated February 16, 2010. (http://www.energy.ca.gov/sitingcases/all_projects.html, accessed February 17, 2010.)

32. Ibid.

- The Energy Commission's committee assigned to the Carlsbad Energy Center completed evidentiary hearings in February (07-AFC-6). Although shown on the Siting, Transmission and Environmental Division's "Energy Facility Status" page as having a commercial operations date of July 2010. Even if certified by June 2010, this 550 MW natural gas-fired combined cycle plant in Carlsbad, San Diego County, would probably not be operational for at least two years.
- The Energy Commission denied MMC Energy's AFC for the Chula Vista Energy Upgrade Project (07-AFC-4) on June 17, 2009. The proposed project was a 100 MW, simple cycle electrical power plant facility to be built in the city of Chula Vista, San Diego County.[33]

Non-California ISO Areas

As in 2009, Imperial Irrigation District's replacement of the existing El Centro 44 MW boiler by the new 128 MW combustion turbine generator is still listed by the Energy Commission as "on hold." This plant was expected to be operational by June 1, 2009, yielding an aggregate addition of 84 megawatts.[34]

Net Imports (Net Interchange)

The net import assumption represents a conservative estimate of potential electricity imports into each region and is based on the western United States/Canada/Mexico electricity system's capability to provide surplus generation during peak demand periods. The interconnected and interdependent wholesale western power market provides reliability benefits as well as broad opportunities for cost savings due to the diverse mix of surplus electricity resources and different load patterns in each part of the western system. Electricity is imported from other western states, Canada, and Mexico for various reasons and involves different types of long-term and short-term transactions.

Some of the imported electricity is either generated at plants that are partially owned by California utilities or is purchased using long-term contracts. The amount of imports associated with these specified sources is relatively stable and does not vary from year to year.

The remaining electricity imports are generally acquired through short-term transactions that are traded on the western wholesale power market. These acquisitions represent almost half of the total annual imports of electricity. California utilities and generators purchase short-term market electricity to reduce costs, such as those associated with operating more expensive generation facilities within California.

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33. *Final Commission Decision, June 2010* (http://www.energy.ca.gov/2009publications/CEC-800-2009-001/CEC-800-2009-001-CMF.PDF, accessed February 17, 2010.)

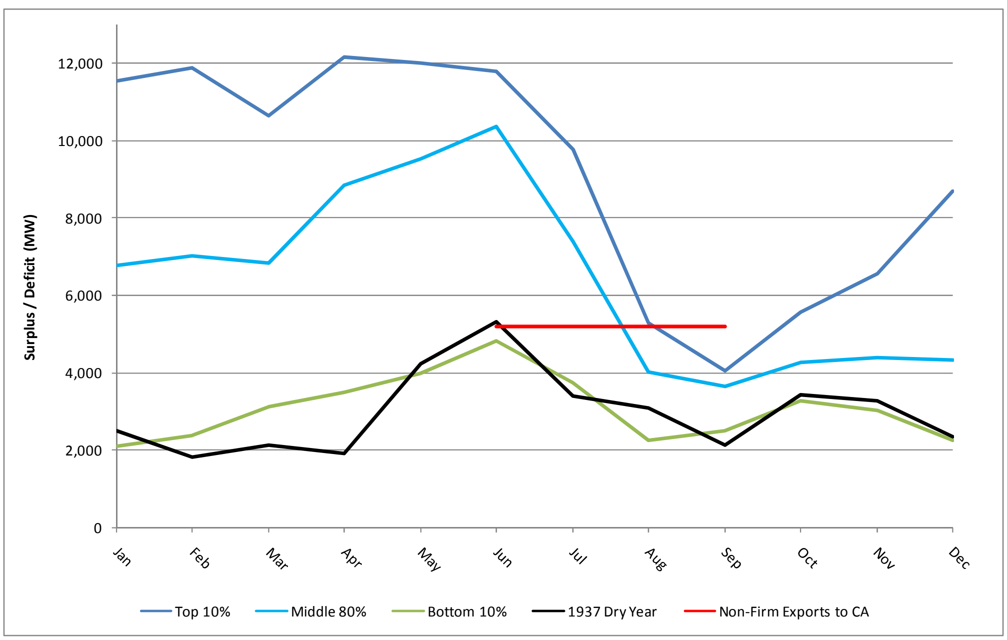
34. www.energy.ca.gov/sitingcases/all_projects.html Accessed January 6, 2010.)

Short-term electricity purchases also occur to occasionally meet unexpected supply shortfalls due to higher-than-expected demand or facility outages. The California ISO facilitates the purchase of short-term electricity supplies if a day's actual demand proves to be higher than the day-ahead forecast predicted and for which an inadequate supply of generation was scheduled.

The amount of short-term imports may vary seasonally and usually depends on hydro-generation conditions in both California and the Pacific Northwest. The amount of short-term imports may also vary day-by-day, depending on different market incentives or operating constraints due to generator and/or transmission conditions. Energy Commission staff has determined that there is a sufficient surplus capacity in neighboring regions to meet the net interchange estimates detailed below. **Figure A-1** provides a summary of the Bonneville Power Administration forecast of surplus capacity in the Northwest by various water conditions. Even in the driest year on record (1937), there is enough surplus capacity in the region to meet the interchange assumption included in the *2010 Outlook*.

The staff determined the amount of surplus resources in the Southwest by conducting internal modeling simulations and reviewing the most currently adopted Western Electricity Coordinating Council's *2009 Power Supply Assessment* (October 1, 2009).

Figure A-1: 2010 Forecast of Northwest Regional Surplus/Deficit by Water Year



Source: *Bonneville Power Administration 2009 Pacific Northwest Loads and Resources Study* ("White Book"), pp. 144-147
Source: Energy Commission staff

Net Import Details by Region

Table A-4, Table A-5, Table A-6, and **Table A-7** provide details on the individual components of net interchange for each of the four regions. Some imports are identified as capable of carrying their own reserves since transmission is the factor that limits capacity exchange, and there is sufficient surplus to replace a generation outage from the exporting region.

The Los Angeles Department of Water and Power (LADWP) Control Area interchange values provided in **Table A-4** and **Table A-5** include power that is wheeled through the LADWP Balancing Authority Area to other municipal utilities served by the California ISO. **Table A-5** reflects an export level on Path 26 of 1,500 MW at time of NP 26 peak load conditions.

Table A-4: Statewide Net Interchange (MW)

Northwest Imports over the California-Oregon Intertie (COI)[35]	4,000
Southwest Imports	4,100
Pacific DC Intertie (California ISO)	2,000
LADWP and IID Balancing Authority Areas	3,018
Total	**13,118**

Source: Energy Commission staff

Table A-5: California ISO Net Interchange (MW)

California ISO Share of NW Imports (COI)	2,300
WAPA Central Valley Imports	950
Southwest Imports	4,100
Pacific DC Intertie (California ISO)	2,000
Net LADWP Balancing Authority Area Interchange	1,000
Total	**10,350**

Source: Energy Commission staff

Table A-6: NP 26 Net Interchange (MW)

California ISO Share of NW Imports	2,300
WAPA Central Valley Imports	950
Path 26 Exports	(1,500)
Total	**1,750**

Source: Energy Commission staff

35. Imports assumed to carry reserves as transmission is the limiting factor.

Table A-7: SP 26 Net Interchange (MW)

Path 26	3,000
California ISO Share of Pacific DC Intertie	2,000
Net SW Imports	4,100
Net LADWP Balancing Authority Area Interchange	1,000
Total	**10,100**

Source: Energy Commission staff

1-in-2 Summer Temperature Demand (Average)

The peak demand forecast for the *2010 Outlook* is the current adopted Energy Commission demand forecast.[36] Documentation of forecast assumptions and methods are included in that report. For discussion of weather normalization methods, see the ***Probability of Demand*** section in this report.

Interruptible and Demand Response Resources

There are several mitigation measures available to the California ISO and individual utilities to respond to adverse conditions when operating reserves fall below minimum acceptable levels. **Table A-8** details the expected impacts from utility demand response and interruptible programs, and other demand resources contracted by utilities.

The estimated impacts for programs run by the three large investor-owned utilities (IOUs) were developed to support implementation of 2010 resource adequacy requirements for California Public Utilities Commission (CPUC)-jurisdictional LSEs. CPUC and Energy Commission staff reviewed and revised the projected impacts to ensure that impacts are calculated consistently with the load impact estimation protocols developed in the CPUC demand response proceeding, and that projected enrollments are reasonable. An additional 110 MW of demand response from pumping load in SP 26 is included in **Table A-8** in the SCE Interruptible category. The NP 26 and SP 26 Other Demand Response categories show demand response reported by publicly owned utilities that are in the California ISO on their *2009 IEPR* supply forms. The Rest of State Resources category includes demand resources reported by LSEs in balancing authority areas other than that of the California ISO. A detailed explanation of the program categories identified in **Table A-8** follows.

Interruptible Load Programs

Interruptible resources are composed primarily of two general types of programs: interruptible rates and direct control. In interruptible rate programs the customer receives discounted energy and demand charges for load subject to curtailment during system events. Because customers are subject to non-compliance penalties if demand is above the

36. California Energy Commission. December 2009. *California Energy Demand 2010 - 2020*, CEC-200-2009-012-CMF, http://www.energy.ca.gov/2009publications/CEC-200-2009-012/index.html,

contracted firm service level during events, the compliance rate in recent years has been 95 percent or better.

Direct control programs are those in which the utility can control the operation of customer's equipment. For example, customers receive a bill credit if they allow the IOU to temporarily turn-off or "cycle" their central air conditioner compressor during periods of peak demand.

Table A-8: 2010 Demand Response and Interruptible Load Resources

	Expected MW			
	June	**July**	**August**	**September**
PG&E				
Interruptible Rates	226	226	227	221
Direct Control	71	76	96	97
Total Interruptible	297	302	323	319
Critical Peak Pricing	233	229	235	251
Demand Bidding & Other DR	47	48	49	52
Demand Response Aggregators	112	120	128	138
Total Demand Response	392	398	413	440
Other NP26 Demand Response	2	2	2	2
SCE				
Interruptible Rates	810	793	798	795
Direct Control	379	619	532	638
Total Interruptible	1,189	1,411	1,330	1,433
Critical Peak Pricing	116	116	114	119
Demand Bidding & Other DR	53	53	54	56
Demand Response Aggregators	97	101	99	100
Total Demand Response	266	270	267	275
Other SP26 Demand Response	48	48	48	48
SDG&E				
Interruptible Rates	6	6	6	6
Direct Control	5	19	20	19
Total Interruptible	11	25	26	25
Critical Peak Pricing	32	36	36	37
Demand Bidding	20	21	23	24
Total Demand Response	52	57	59	60
Total CAISO	2,258	2,513	2,468	2,601
Rest of State Resources	313	316	316	313
Total Statewide	2,571	2,829	2,783	2,914

Source: Energy Commission staff

Demand Response Programs

Demand response programs employ a variety of incentive structures to motivate peak demand reduction and do not have penalties for noncompliance. This program category has increased by 350 MW compared to the *2009 Outlook* as the IOUs implement the CPUC direction to promote price-responsive demand.

Critical peak pricing rates offer discounts (energy, demand or both, depending on the particular design) in non-critical hours but charge a premium for energy consumed on a limited number of days when system conditions are forecast to be critical, typically due to high expected demand or supply shortfalls. This forecast includes the effects of PG&E's new Peak Day Pricing Plan, which will be the default rate for large customers by May 2010. Impacts in SCE's Critical Peak Pricing program, which is already the default rate for large customers, are projected to increase by over 100 MW.

In demand bidding programs, participants are paid an incentive for load reductions during curtailment events that are "bid" in to the utility in advance. There is no penalty for not bidding or not fulfilling the bid obligation. These programs have a much lower performance rate (in terms of MW reduced per subscribed MW) than interruptible programs, and the estimated impacts reflect that.

Demand response aggregators are contractors who develop their own demand response programs and provide load reductions to the IOU. When the IOU calls an event, the aggregators are responsible for dropping electrical load on an aggregated portfolio basis equal to their contracted amount.